**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking No. 14-08-013 (Filed August 14, 2014)

COMMENTS ON THE ORDER INSTITUTING RULEMAKING OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC.

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On August 14, 2014, the Commission issued the Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (OIR) in the instant docket, Rulemaking (R.) 14-08-013. According to the OIR, the goal of this rulemaking is twofold: (1) to establish policies, procedures, and rules to guide the California investor-owned utilities (IOUs) in developing their Distribution Resource Plan (DRP) proposals, due July 1, 2015; and (2) to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating distributed energy resources (DER)[1] into the planning and operation of their systems.[2] In the OIR, the Commission requests comments on the scope of the proceeding, the procedural schedule, and a set of sixteen questions.[3] The Interstate Renewable Energy Council, Inc. (IREC) hereby submits these responsive comments.

IREC is a non-profit organization whose goal is to enable greater use of clean energy in a sustainable way by: (1) introducing regulatory policy innovations that empower consumers and

1 Public Utilities Code § 769(a) provides that "'distributed resources' means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles and demand response technologies." *See also More than Smart* at 3, n.B. All further statutory references in these comments are to the Public Utilities Code unless otherwise stated.

2 OIR at 2.

3 *Id.* at 6-8, 11.

support a transition to a sustainable energy future; (2) removing technical constraints to distributed energy resource integration; and (3) developing and coordinating national strategies and policy guidance to provide consistency on these policies centered on best practices and solid research. The scope of IREC's work includes incorporating DER growth into utility distribution system planning and operations. IREC has been or is currently involved in similar proceedings in New York, Massachusetts and Hawaii.

I. Scope of Proceeding

IREC generally supports the proposed scope of the proceeding described in the OIR.[4] Given the Commission's obligation to review, potentially modify, and approve the IOUs' DRPs pursuant to Section 769(d), IREC agrees that it makes sense for the Commission to provide the IOUs with guidance in developing their DRPs. Although Section 769 contains some detail regarding the contents of the DRPs, additional clarity from the Commission prior to their development should help to make the review and approval process as efficient as possible.

IREC proposes one addition to the scope of the proceeding: the consideration of how to improve customer engagement and the incorporation of improved customer engagement into the DRPs. Customers are driving the DER market as they increasingly become interested in and adopt these technologies. To incorporate DER into their distribution planning, it will be critical for the IOUs to understand how to continue to engage customers in managing their energy supply and to leverage that engagement. Using DER in the most effective ways possible will involve new ways of interacting with customers and DER providers. IREC believes it is important to highlight the customer engagement component necessary to the DRPs.

[4] *Id.* at 4-6.

In addition, IREC urges the Commission to expressly declare its intent to coordinate its efforts in this proceeding with the various related dockets and other efforts currently in process. IREC appreciates the Commission's indication that it may explore the relationship between DER deployment, the DRPs and California's greenhouse gas emission targets.[5] IREC suggests that the Commission may also want to explore the relationship between DER deployment and the DRPs with other of California's energy policy goals, including in particular the State's Zero Net Energy goals. IREC also suggests that the Commission coordinate development and review of the DRPs with other proceedings at the Commission, including in particular R.14-07-002 (development of the successor tariff to net energy metering), R.12-11-005 (California Solar Initiative, Self-Generation Incentive Program and other distributed generation issues), R.12-06-013 (residential rate structures), and R.11-09-011 (interconnection of distributed generation and storage).

Finally, IREC encourages the Commission to consider using its constitutional authority to require that the DRPs be updated on a regular basis. Full incorporation of DER into the distribution planning process is likely to take time, and require both near- and long-range visions. It may be appropriate for the DRPs to be update on a bi-annual or other ongoing basis to ensure a full transition to a truly integrated distribution system.

II. Procedural Schedule

IREC believes that the proposed schedule for the proceeding is reasonable, given the July 1, 2015 deadline for the IOUs to submit their DRPs.[6] We note, however, that the proceeding encompasses a number of complex and difficult issues, which may be hard to discuss in depth in

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[5] *Id.* at 9.

[6] *Id.* at 10-11.

the short timeframe available. IREC hopes that the Commission's consideration of these issues will continue past that deadline in this docket as well as other existing and future dockets.

Due to the short timeline proposed for developing guidance on the DRPs, IREC suggests that the Commission hold the workshop on the Staff Proposal, which the OIR proposes for November 2014 "if requested."[7] The opportunities for stakeholder questions and input prior to the development of the DRPs are very limited, and IREC believes that the inclusion of this workshop will be a valuable additional forum for information-sharing and feedback prior to the written comments anticipated in December 2014.

III. Responses to Questions

As the OIR notes, since 2001, the Public Utilities Code has stated that "[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost."[8] Despite the Legislature's and Commission's successful efforts to promote DER through various policies and programs, this integration of DER into distribution system planning has not occurred as effectively as it could. The need for more thorough integration is only increasing as penetrations of solar photovoltaics (PV) reach new levels. The new statutory mandate put forth in AB 327 for the IOUs to develop DRPs offers an exciting opportunity to realize this important goal.

IREC provides specific responses to the Commission's questions below. Throughout our responses, we offer a vision of utility distribution planning in which the utility is indifferent both to the technology used (traditional wires solutions versus non-wires-based solutions such as DER) as well as the ownership of that technology (utility versus non-utility). Such a framework

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7 *Id.* at 10.

8 *Id.* at 2-3 (referring to Cal. Pub. Util. Code § 353.5).

would leave the utility with the discretion to choose the most cost-effective distribution system investments that best meet all of the various public policy goals identified by the Commission. While the DRPs are just a step on the path toward this vision, we believe they are an important one.

As far as more concrete focal areas, IREC suggests that both the existing interconnection procedures and procurement programs will require additional attention as part of this proceeding. Regarding interconnection, IREC believes that the DRPs are part of a broader, necessary evolution of the serial interconnection procedures into a more integrated interconnection and distribution planning process. By taking a more holistic look at the integration of DER into the distribution system, the Commission and the IOUs will be better able to minimize the costs of interconnecting DER, and appropriately allocate both costs and benefits across customers. Regarding procurement programs, IREC notes that the programs in place to date have not been as effective as they could be at driving DER at optimal grid locations. To improve these programs, IOUs will need to collect the information necessary to determine the best grid locations, and will also need to share this information effectively with non-utility providers and customers. In addition, the Commission and the IOUs will need to establish methods for transferring compensation for locational values as appropriate, in many cases within the framework of the procurement programs.

1. **What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?**

As indicated above, IREC believes that the DRPs should lead the IOUs toward planning and investing in their distribution systems in a way that is indifferent to both the technology used and the ownership of that technology. Within this framework, the IOUs should strive to cost-effectively achieve policy priorities clearly articulated by the Commission, which should include: renewable energy procurement, including the procurement of distributed renewable energy; reduction of energy usage through energy efficiency, demand-side management, and demand response; customer satisfaction and engagement; safety; reliability; resiliency; and greenhouse gas emission reductions. In some cases, achievement of these policy goals will be most cost-effectively accomplished by traditional, wires-based solutions owned by the IOUs. In others, however, it will be more cost-effective to rely on DER, either utility- or third-party-owned, and other third-party-provided products and services.

This will be a departure from the current distribution planning paradigm, in which the IOUs' generally prefer wires-based solutions that they own. In large part this is due to the bias for these types of capital-intensive, utility-owned solutions engendered by the current ratemaking framework, which ties IOUs' profits to their capital investments. It is also a reflection of the now outdated view that the distribution system is primarily a vehicle for one-way power flows where nearly all generation is provided via central station generators located on the transmission system remote from load. IREC recognizes that this proceeding does not set out to reform California's ratemaking framework. We believe, however, that it is important to acknowledge that this framework fundamentally does not encourage IOUs to integrate DER into their distribution planning, and may need to be revisited in the future.

In the nearer term, IREC suggests that four areas will be especially important to ensuring the success of the DRPs.

- Reconsideration of the interconnection cost-allocation process.
- Procurement mechanisms that encourage DER in optimal locations.

- Transparency of grid and customer data.
- Tariffs and market conditions that allow for the appropriate transfer of benefits and costs.

We explore these ideas further in the questions below.

2. What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

IREC believes that Section 769 clearly lays out the specific elements required in the DRPs. These include: the identification of "optimal locations for the deployment of distributed resources"; the evaluation of the "locational benefits and costs of distributed resources located on the distribution system," pursuant to certain criteria; proposing or identifying "standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objective"; proposing "cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the location benefits and minimize the incremental costs of distributed resources"; the identification of "any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers"; and the identification of "barriers to the deployment of distributed resources, including, but limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service." While the majority of these components are addressed by the various questions posed in this OIR, IREC notes that the Commission has not explicitly asked for feedback regarding the identification of barriers to the deployment of DER. We believe this is a critical component to the discussion surrounding the DRPs: if barriers are clearly identified, the Commission and the IOUs can more easily figure out how to overcome them.

IREC also suggests that the Commission require the IOUs to address both short-term and long-term strategies in their DRPs. Short-term steps should include changes that can be made in the next one to five years, such as particular investments necessary to integrate DER, and particular tariffs, contracts or other mechanisms for deploying DER. As far as longer-term strategies, IREC suggests that the Commission require the IOUs to provide 10-year and 20-year visions for their distribution systems in their DRPs. While these visions may not be as specific as the shorter-term steps that the IOUs will identify, they will help provide context and direction to the IOUs' DRPs overall. Having the IOUs articulate their longer-term strategies will also help the Commission to ensure the IOUs' plans are generally aligned with the Commission's own longer-term vision.

In addition IREC suggests that the Commission should require the IOUs to incorporate into their DRPs a plan for reporting on their progress toward both their short- and long-term goals at regular intervals and, as noted above, to update their DRPs on a regular basis. In this way, the Commission will be able to ensure that an appropriate framework is in place to monitor the IOUs achievement of the objectives of Section 769.

3. What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

The process of identifying optimal locations for DER needs to take into account both existing system conditions as well as foreseeable changes in energy demand, including changes in demand that result from installation of customer sited DER. An optimal location for one type of DER may not be the optimal location for another type of DER. For example, optimal locations for distributed solar PV may initially include areas on the system where there is an opportunity to serve nearby load and where existing system capacity exists to accommodate new generation without the need for significant upgrades. On the other hand, the optimal locations for other

DER, such as energy storage and electric vehicles, may be where there is or will be an excess of generation at certain peak periods. Looking past load and generation ratios, there may also be areas identified as optimal when there is a need for ancillary services to maintain system balance and power quality. Thus, IREC believes that the identification of optimal locations may need to be broken into different categories.

Through the requirements of the Renewable Auction Mechanism (RAM) program[9] the Commission has already taken the first step at having the utilities identify "preferred" areas for interconnection of distributed generation. Generally speaking these areas are those located close to load where there are no known system constraints, but these broad strokes need to be further refined. In addition, little progress has been made to identify locations where DER may help to minimize or eliminate the need for system upgrades that would otherwise be required to accommodate greater amounts of customer-sited PV or other generation.

One good starting point for evaluating factors to consider in identifying optimal locations may be the type of system conditions that are identified in Rule 21's pre-application report criteria (Section E.1). The pre-application criteria are intended to help distributed generation customers identify the best grid locations for their projects in advance of submitting an application. Similarly they may be a starting point for considering what factors need to be evaluated in determining whether capacity exists for new generation. They include such factors as available capacity, peak and minimum loads, circuit voltage, existing protective devices, limiting conductor ratings and known system constraints. Together these and other criteria can help to identify the grid locations at which the locational benefits of distributed generation and other DER, discussed in response to Questions 4 and 7, can be maximized. A more detailed

[9] *See* D.10-12-048, Decision Adopting the Renewable Auction Mechanism, R.08-08-009, at 68-73, 85 (Findings of Fact ¶¶ 42-44), 92 (Conclusion of Law ¶ 44) (Dec. 17, 2010).

analysis of specific circuits may be necessary to identify optimal locations for other DER. The Integrated Distribution Planning approach, discussed below and referenced in the *More Than Smart* paper, may be a method for identifying circuits where those specific services may be needed.

4. What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Specific attributes associated the location of DER that should be considered in developing their locational value include:

- Decrease in system losses. Losses are related to load and certain DER may lower circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any valuation needs to capture both the losses related to the energy not delivered to the DER customer and the reduced losses to serve other customers.
- Avoided transmission and distribution capacity. In particular, circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs. Depending on their location, DER can also help to defer transmission investments, which are usually substantial.[10]

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10 *See, e.g.*, Regulatory Assistance Project, *U.S. Experience with Efficiency as a Transmission and Distribution System Resource* 18 (Feb. 2012), *available at* www.raponline.org/document/download/id/4765 ("A number of studies have suggested that aggressive, geographically targeted efficiency programs can meet T&D reliability objectives. More important, analyses of the actual deployment of efficiency as alternatives to T&D in several jurisdictions have concluded that supply-side investments were deferred for at least some period of time."); Pace Energy & Climate Ctr. & Synapse Energy Econ., Inc. (for NYSERDA), *Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: a Summary Analysis of DG Benefits and Case Studies* 6, *available at* www.synapse-energy.com/Downloads/SynapseReport.2011-02.NYSERDA.DG-Benefits-and-Case-Studies.07-

- Grid support services provided by the DER, including voltage regulation and power quality control. For example a solar generator using a smart inverter, or solar generation paired with storage, can offer significant ancillary services to the grid depending on their locations.

IREC suggests that these values should be part of the public valuation tool under development in R.14-07-002, in which the successor tariff to net metering is being considered. In turn, that tool may be useful to analysis conducted within this docket, at least with respect to net-metered projects. The valuation analysis in this docket needs to look beyond just solar PV, however, to capture the full range of values DER can offer. For example, as IREC suggested in R.14-07-002, the combination of on-site PV generation with energy storage can substantially increase its value, and therefore these DER should be considered independently and together. In addition, IREC notes that these locational benefits make up only a portion of the full value of DER, as discussed in response to Question 7.

IREC believes that the optimal means for compensating DER owners/operators for locational value will vary by type of DER and the program under which it is operating. For example, the means for compensating a net-metered solar facility for any locational value will likely be different than the means for compensating a larger wholesale generator with a RAM contract. We suggest that this may need to be an issue that is differentiated by the various procurement programs, some of which are contract-based and others of which are tariff-based. IREC understands that the locational value of net-metered projects and compensating customers

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081.pdf (Feb. 2011), ("In the right circumstance, DG/CHP has the potential to more precisely match growing energy demand locally and incrementally, thus avoiding or deferring the need for and the costs of upgrading the T&D system. . . . The resulting deferral of T&D investment can release significant investment value to be utilized in other ways.").

for that value are issues already under consideration within R.14-07-002, and suggests that discussion in that docket should inform discussion in this one.

5. What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

As indicated in our response to Question 1, IREC believes the Commission and the IOUs will need to take a close look at, among other things, the existing interconnection and procurement policies as part of the development of the DRPs.

Regarding interconnection, IREC views the development of the DRPs as an important part of the movement from the current serial interconnection process toward the complete integration of DER into distribution system planning. The implementation of a group study process is likewise a key step in this evolution: utilities now allow certain projects to be studied as a group, and to share the costs of studies and upgrades, in order to make the interconnection more efficient and cost-effective.[11] IREC believes that similar incremental improvements to the interconnection process could effectuate more coordinated planning that more properly allocates costs across interconnecting customers and, potentially, all ratepayers. To this end, together with Sandia National Laboratories, IREC developed the concept of Integrated Distribution Planning (IDP),[12] based on the Proactive Approach to interconnection being implemented in Hawaii.[13] Under the IDP framework, the utility determines the likely DER growth on its distribution system over one year, based on its interconnection queue and other data. By studying the

11 *See* D.14-04-003, Decision Adopting Revisions to Electric Tariff Rule 21 to Include a Distribution Group Study Process and Additional Tariff Forms, R.11-09-011 (April 10, 2014).

12 *See Integrated Distribution Planning (IDP) Concept Paper, A Proactive Approach for Accommodating High Penetrations of Distributed Generation* (May 2013), *available at* www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution-Planning-May-2013.pdf

13 *See* Order No. 32053, Ruling on RSWG Work Product, Docket No. 2011-0206, at 33, 49-57 (April 28, 2014), *available at* http://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32053.pdf (requiring HECO to implement a DG Interconnection Plan (DGIP) consistent with the Proactive Approach and describing the details of that approach).

aggregate capacity of existing facilities and the hosting capacity of existing equipment, it also determines its available hosting capacity for additional DER. Using this information, the utility assesses whether its existing equipment can accommodate anticipated DER installations and then plans for upgrades in areas where growth outpaces hosting capacity. IDP opens the door to modifications to the cost allocation process for these upgrades. For example, a utility could build upgrades in advance to meet an anticipated need. It could then rate base part of this cost, accounting for the value that the upgrades and associated DER provide to the grid, and charge DER customers portions of the remaining cost as they apply to interconnect to that area of the grid. It also creates a longer term planning process for circuits that will allow the utility to evaluate and potentially procure DER in advance that may serve as substitutes for, or complements to, traditional upgrades at lower costs.

IREC believes that procurement programs will also need to be modified in order to direct DER to locations where they can be used optimally. As the Commission is aware, California already has a number of policies in place to encourage renewable energy development, including the Renewables Portfolio Standard (RPS), the RAM, Renewable Market Adjusting Tariff (ReMAT), and net energy metering (NEM). To date, these programs have not focused on the optimal siting of projects, and as a result projects have not necessarily been sited to maximize their potential value. IREC suggests that as part of the DRPs the IOUs could identify ways in which these existing programs could be modified to encourage optimally sited DER, and/or offer additional procurement program ideas to accomplish the same goal.

6. What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

IREC has no response to this question at this time. We reserve the right to respond in reply comments.

7. What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

As indicated in response to Question 4, IREC believes that the benefits directly tied to grid location make up only a portion of the full value of DER. The full set of benefits of DER include: avoided energy costs, avoided system losses, avoided generation capacity costs, avoided transmission and distribution capacity costs, grid services benefits, financial benefits, reliability and resiliency benefits, economic benefits, and environmental and other societal benefits. IREC discusses these benefits as they pertain to solar distributed generation in *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*.[14] Many if not all of the same benefits accrue to other types of DER.

In pursuing DER as part of their distribution planning, the IOUs should consider the full value of these resources. The locational value of DER is emphasized in Section 769 and carries obvious importance with respect to grid planning, in that the benefits associated with the location are directly responsive to the grid situation at that site. Nonetheless, in considering the DER as part of distribution system planning, it is essential to evaluate all of their benefits and costs, and compare that total value proposition with those of alternative solutions, such as the wires-based solutions IOUs have historically preferred. Evaluating the full values of the various options in this way will allow the IOUs to compare not just the immediate grid benefits of the options, but

[14] Available at www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

also their ability to achieve the various other policy goals put forth by the Commission, which are broader and included various economic, environmental, and other societal benefits. This will be an important step toward better aligning the utilities' investment decisions with the public policy decisions of the Commission and the Legislature.

8. What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

IREC has no response to this question at this time. We reserve the right to respond in reply comments.

9. What types of data and level of data access should be considered as part of the DRP?

IREC believes that two types of data access will be important to consider as part of the DRP development process.

First, the Commission and the IOUs should consider whether the IOUs are providing adequate access to customer usage data to allow DER providers to offer products and services that provide maximum value to customers and to the grid. IREC recognizes that the Legislature and the Commission have already taken important steps in this direction, with the intent of providing access to customer usage data while at the same time protecting customer privacy and ensuring cybersecurity. IREC suggests that the Commission may need to revisit its rules in relation to the DRPs to make sure that they allow for the transparency necessary to effectuate the goals of Section 769.

Second, the accessibility of distribution system data is also going to be critical to effectuate the efficient and effective deployment of DER. In some cases, the IOUs are not yet gathering or analyzing the data necessary to identify optimal grid locations for DER, so an important first step will be to ensure that they make the necessary investments and process changes to do so. The IDP concept discussed above may be one possible method to facilitate this process. Beyond the acquisition of the necessary data, it will also be critical that the IOUs provide access to grid data to customers and DER providers so that they can optimally locate their DER. The pre-application report discussed in response to Question 3 and the RAM preferred resources maps are modest steps in this direction but increased transparency and information-sharing will be necessary.

10. Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

Compliance with Section 769 will entail a marked shift in the way that IOUs currently plan and invest in their distribution systems. Pilot or demonstration projects may help IOUs to become familiar with newer technologies or approaches, and therefore could be a component of the DRPs. Section 769 does not mention such projects, however, and IREC does not believe that they should be a primary feature of the DRPs. Rather, we suggest that the DRPs should focus more holistically on re-envisioning how the IOUs approach the management of their distribution systems, with particular attention to the integration and optimal use of DER, as mandated by Section 769.

11. What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

IREC believes that it would be appropriate for the Commission to establish metrics associated with its goals for the DRPs to monitor their implementation over time. As explained in response to Question 1, IREC believes that the Commission should clearly articulate its goals at the outset. IREC's suggested goals include: renewable energy procurement, including the procurement of distributed renewable energy; reduction of energy usage through energy efficiency, demand-side management, and demand response; customer satisfaction and engagement; safety; reliability; resiliency; and greenhouse gas emission reduction. Although these goals are familiar to the Commission and the IOUs given various other policies and programs already in place, IREC believes that putting them forth specifically in the context of the DRPs will help clarify what policy priorities the IOUs need to balance in determining distribution investments. The DRP metrics would flow from this set of measurable goals. In addition, IREC believes that the Commission should continue to make sure that any investments and other decisions that the IOUs make are also cost-effective, taking into account the full value of DER as discussed in response to Question 7.

Given the focus of Section 769 on encouraging the integration of DER into distribution planning, IREC also believes that metrics specifically associated with DER should also be included. These could include measurements of the number and type of DER products and services in which the IOUs are investing or obtaining in other ways, such as through tariffs or contracts. This would help the Commission to understand to what extent the IOUs are achieving this concrete statutory goal.

Finally, IREC notes that both statewide metrics applicable to all IOUs and specific metrics applicable to each IOU individually may be appropriate. IREC suggests that the Commission should determine which metrics will be appropriate on a statewide basis and should encourage the IOUs to propose any individualized metrics they believe are appropriate.

12. What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

At a basic level, the Commission must ensure that the DRPs incorporate each of the components identified in Section 769. Beyond that, IREC believes that the IOUs' DRPs should clearly demonstrate both the IOUs' proposed path toward the Commission's various policy objectives and how the IOUs plan to balance those objectives. As part of doing this, the IOUs should expressly incorporate any global metrics identified by the Commission as well as any metrics specific to each IOU's particular distribution system and DRP. In addition, IREC urges the Commission to ensure that the IOUs explain in their DRPs how they will give equal consideration to DER and traditional, wires-based solutions. This should include identifying both barriers to the integration and incorporation of DER into distribution planning today, as well as how the IOUs' proposed approaches overcome these barriers.

In addition, IREC notes that it will be important for the Commission to ensure that the DRPs are as consistent as possible, while also allowing flexibility for the IOUs to account for the particular systems and operational contexts. The DRPs should address similar topics in a similar format so that the Commission and other stakeholders can review and compare them.

13. Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

IREC believes this is a critical question. In particular, we believe that it is important to consider the benefits of utility versus non-utility (both customer and third-party) ownership. As discussed in response to Question 1, the IOUs have an inherent bias toward utility-owned resources due in part to the current ratemaking framework. This bias may result in neglecting to take advantage of the benefits that non-utility-owned DER may provide to both customers and the grid. As is the case with utility-scale generation facilities, however, it may only be necessary for the IOU to have sufficient visibility into and/or control over the DER to ensure it meets the IOU's needs.

Regarding DER installed behind a customer's meter specifically, such as customer-sited energy storage combined with on-site generation, IREC expects that such DER would not require

IOU ownership, and instead would be owned by customers themselves or third parties. In these instances, however, the Commission should consider how to ensure that IOUs recognize the benefits that these customer-sited, customer- or third-party-owned DER provide, and offer appropriate compensation for them. In addition, the Commission should ensure that IOUs enable non-utility parties to identify where installation of non-utility-owned DER may have significant system value, as discussed in response to Question 9. Effective mechanisms to value, maximize and transfer these benefits are not currently in place.

That being said, IREC acknowledges that in practice optimal DER performance may be most cost-effectively achieved through IOU ownership in certain instances. Some DER are so closely tied to reliability that direct utility engagement, including potentially ownership, may be required. Likewise certain DER may require direct utility engagement to contribute to system efficiency or resiliency. For example, certain applications of energy storage, such as storage installed at the substation, may be optimized in the near term through utility ownership and/or management, although other applications can function just as well when owned by customers or third parties. Finally, there may be new DER technologies that an IOU could pioneer, especially if the technology requires testing in a pilot situation or is too expensive to be employed competitively but shows great promise, and this could necessitate IOU ownership.

IREC suggests that it will be important for the Commission to provide some guidance on this issue to the IOUs prior to their development of the DRPs. The IOUs will then be tasked with demonstrating how to meet the Commission's policy objectives. On this front, IREC believes it will be important that the IOUs articulate in their DRPs how they will encourage non-utility ownership of DER given the structural bias toward utility ownership.

14. What specific concerns around safety should be addressed in the DRPs?

IREC supports the Commission's focus on safety issues associated with distribution planning.[15] We recognize that many DER are relatively new to IOUs and that ensuring safety will continue to be of paramount importance as the IOUs work to understand the operation of these technologies on their systems. While we do not offer specific safety concerns here, we agree that these concerns should be taken into account as the Commission and the IOUs strive to incorporate DER more comprehensively into IOU distribution system planning.

15. What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs?

If implemented effectively, the DRPs envisioned by Section 769 will significantly alter the way in which the IOUs manage their distribution systems. Their effective implementation will require modifications to other associated policies, as discussed above, including procurement programs, interconnection procedures, data collection and sharing, and tariffs and other market mechanisms that transfer benefits and costs between market actors. IREC believes that both the Commission and the IOUs have important roles to play in the successful implementation of the DRPs. As mentioned in our response to Question 1, however, IREC believes that the current ratemaking paradigm represents a fundamental challenge to the successful integration of DER into distribution system planning. While the DRPs are an important first step toward reenvisioning the IOUs' distribution grids, IREC believes that it may also be necessary to revisit California's ratemaking framework to achieve the broader vision articulated in Section 769. For the IOUs to fully incorporate DER into their distribution system planning in the long-term, it will be important to ensure that the IOUs' cost-recovery and profit

[15] OIR at 8-10.

incentives are better aligned with California's policy goals. We recognize that this is likely outside the scope of the current proceeding, but we nonetheless raise it for the Commission's further consideration.

16. Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

a. Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?

IREC believes that the framework presented in the *More Than Smart* paper offers an interesting starting point for discussion. We agree that it is important to identify policy goals up front and note that the policy goals listed in the framework—efficiency, reliability, sustainability and affordability—and the various "integrated system qualities" listed below them mesh well with the policy goals IREC identified in our comments above.

We believe, however, that two important goals are missing from these two tiers of the framework. First, as we noted above, IREC believes that customer engagement should be a critical component of the DRPs, and should be articulated within the policy goals and guiding principles. In addition, IREC believes that the framework insufficiently emphasizes the environmental and other social goals associated with a more integrated distribution system, in particular the reduction of carbon dioxide emissions.

In general, IREC notes that ideas presented in the paper may each have value, but the paper's preliminary explanation of many of the concepts does not provide a sufficient basis for prudent regulatory action. The underlying assumptions, technical challenges and costs and benefits of many of the proposals warrant further specificity and support before IREC can provide meaningful comments on those concepts.

b. Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?

We appreciate the reference in this section to IREC's IDP concept discussed above, which we agree is one means of determining optimal locations for DER.[16] In addition, we reiterate our strong support of the idea in this section that greater access to grid asset and operational data is necessary to undertake the analyses required to achieve the goals associated with the DRPs.[17] Likewise we support the idea of increasing the transparency and stakeholder engagement within the distribution planning process, although we agree that this will need to be balanced against overburdening and slowing down the process unnecessarily.[18]

c. Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?

IREC supports the idea that the distribution system will need to evolve from "a closed single purpose system to a more open, flexible, operationally visible and resilient platform that can accommodate anticipated DER integration and future innovations."[19] We agree that this will likely entail revisiting the interconnection process in an effort to improve information-sharing and lower costs.[20] IREC believes, however, that the recommendation of a "node-friendly electric network" needs further explanation and evaluation.[21] The paper does not explain the exact benefits that will be achieved by moving towards a networked distribution system or why those

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16 *See More Than Smart* at 9, n.19.

17 *See id.* at 9, 11 (Guiding Principle 3).

18 *See id.* at 10-11 (Guiding Principle 4).

19 *Id.* at 13, 16 (Guiding Principle 5).

20 We note that IREC participated in the interconnection reform process in Massachusetts cited in this section and that the majority of the changes adopted in that state mirror the procedures already in place in California. *See More Than Smart* at 13, n.27.

21 *See id.* at 12-13.

benefits outweigh the potential infrastructure investments required to achieve such a transformation. While IREC does not necessarily oppose this idea, it warrants further exploration, preferably in a public forum, before becoming actionable. In addition, IREC would like to see further explanation of the four "end-states" identified in the paper.[22]

d. Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?

IREC generally supports the concept of moving toward a "distribution system operator" paradigm, in which the utility would manage the physical operation of the system as well as the associated market operation.[23] We note that this is similar to the role of the "distribution system platform provider" under discussion within New York's Reforming the Energy Vision proceeding. IREC believes that a full transition to this role is likely beyond the scope of this proceeding and will require other policy and regulatory changes, including reconsideration of the ratemaking framework as discussed above.

e. Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?

IREC generally agrees with the statement that "the issue isn't *if* or *when*, but rather *how* do we enable integration of flexible DER into the bulk power and distribution systems."[24] We believe the DRPs are an exciting opportunity to address how this will happen. IREC also agrees that the four components listed in this section will be key elements of the DRPs to cover and we address three of them in our comments above: the relationship between DER and the DRPs and interconnection costs; allowing DER to meet reliability and power quality services; and enabling

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22 *See id.* at 12.

23 *See id.* at 16-19.

24 *Id.* at 19.

DER to serve as alternatives to traditional distribution investments.[25] We also reiterate our strong support for the need to transparently identify the values of DER and monetize those values for both utility and non-utility market participants.[26]

f. Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?

IREC looks forward to a discussion within this or another proceeding regarding how the DRPs would fit into a roadmap transitioning today's IOUs toward a future "distribution system operator" or similar model. While we believe the DRPs play an important role, and touch on each component identified in the roadmap proposed in the white paper, we believe that additional policy and regulatory changes will be necessary, as well.

IV. Conclusion

Yet again California is leading the way on critical energy policy issues, and joins a handful of other states taking an in-depth look at the modifications and innovations needed to effectively incorporate DER into the planning and operation of the existing and future electric systems. IREC believes that the IOUs' DRPs hold much promise in moving California toward a more cost-effective and sustainable energy future. We look forward to engaging in this proceeding going forward.

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25 *See id.* at 19.

26 *See id.* at 21-22, 23 (Guiding Principle 15).

Respectfully submitted at Oakland, California,

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